Update to: Supplemental Financial Information Booklet

July 23, 2001

B. Energy Purchase Costs and Financing Plan

Update to Methods and Assumptions for Estimating the Requirement for Net Short Energy Purchases

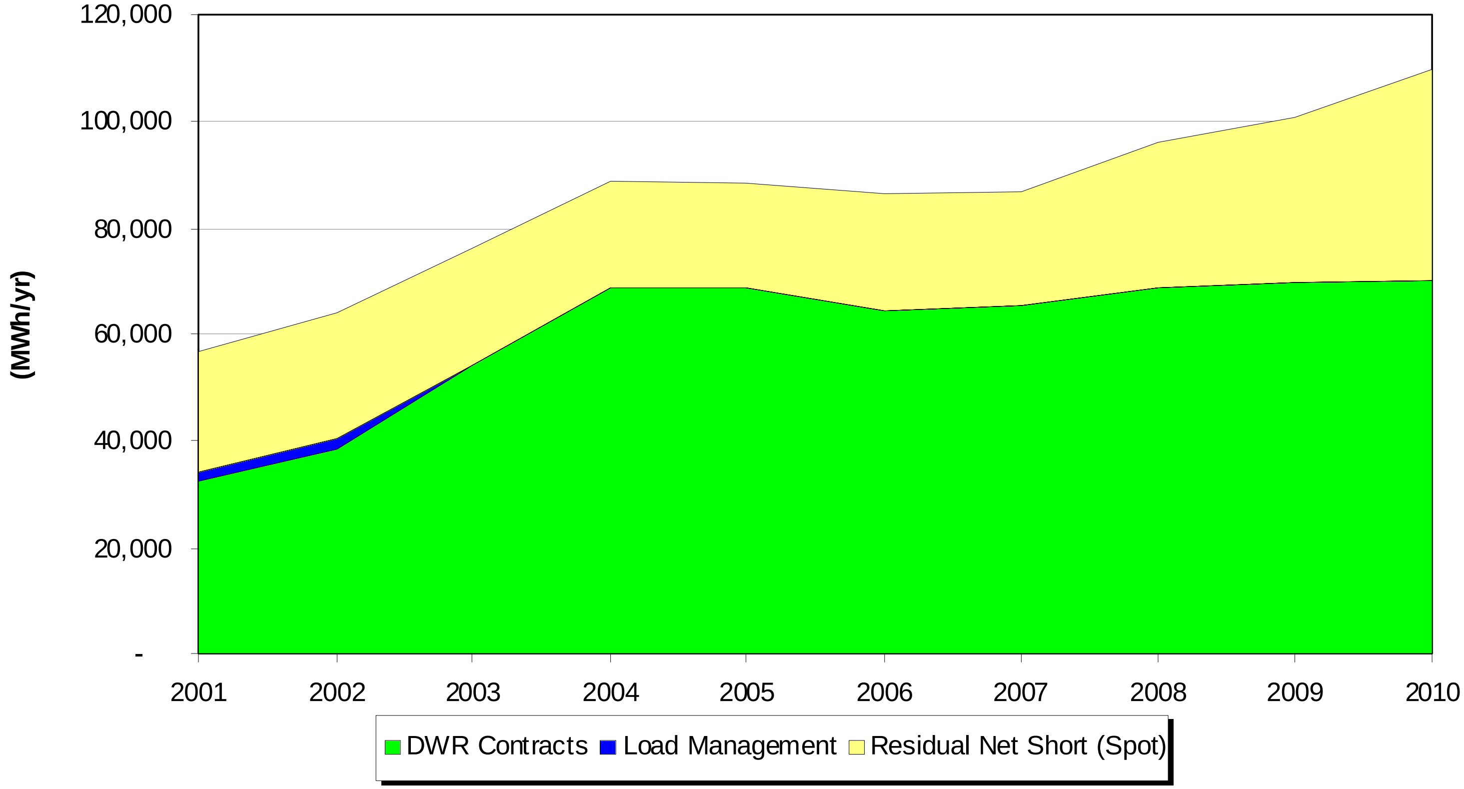
July 23, 2001

Navigant Consulting/Montague DeRose

Definition of Net Short Energy

- Net Short is the difference between:
  - Total electrical loads of the three investor-owned utilities ("IOUs"), and
  - The combined energy production of:
    - IOU's remaining owned generation (nuclear, hydro and some fossil fueled)
    - Qualifying Facility ("QF") output
    - Remaining bilateral power purchase agreements between the IOUs and others
- Figure 1 presents the estimated annual quantity of net short energy purchases compared to expected quantities of DWR's energy purchase under long and short-term contracts
- The energy obtained from the contracts reflect expected levels of operation from generation which is subject to dispatchable contracts

Figure 1
Statewide Annual Energy Net Short (MWh) and Contract Energy



(1) 2001 Totals are based on April through December data.

(2) DWR Contracts include a total of 40 executed contracts and 18 agreements in principle.

(3) Contracted energy estimates reflect expected energy dispatched to IOU retail customers. Contracts include additional dispatchable energy, and some off-system sales occur.

Source of Net Short Energy Requirements

- DWR retained independent, professional energy consultants (Navigant Consulting) to develop estimate of net short requirements
- Baseline data provided by Pacific Gas & Electric ("PG&E"), Southern California Edison ("SCE"), San Diego Gas and Electric ("SDG&E") and California Independent System Operator ("ISO")
- Forecasts were modified to develop consistent estimated hourly and day of the week net short energy needs, for each month from 2001 through 2010
- Net short energy requirements after 2003 extrapolated from adjusted 2001-2003 forecasts
- Forecasts were adjusted for conservation, QF availability on line and hydroelectric generation production assumptions, and the return of direct access customer loads to the IOUs, from 2001 to 2002

Adjustments to IOU Load Estimates

- Prior to adjustment, forecasts assumed approximately 1.7 percent annual growth in peak demand (revised from 2.0 percent) and 1.4 percent annual growth in annual energy requirements (revised from 2.0 percent) on average through 2010
- The base level forecasts were reduced based upon an assumed 4 percent conservation in demand in all hours due to observed customer behavior year-to-date 2001
- Based on announced retail electric rate increase of approximately 30 percent, assumed 2 percent incremental reduction (revised from 3 percent) in demand as of June 1, 2001 for price elasticity effects. Price elasticity effects expected to increase by 2002 to 3 percent to reflect lag effect of consumer response to increase prices
- 4 percent observed conservation and 2 percent reduction (revised from 3 percent) in loads due to price elasticity are assumed to decrease after 2002 as shown in Table 1

Impacts of Qualifying Facility Production on Net Short

- Less than 5 percent of QF capacity is presently off-line as of July 2001
- Assumes June 2001 through 2010 that on average, 10 percent of QF capacity is out of service (as shown in Table 1)

Table 1
Adjustments to Net Short for Non-Programmatic Conservation and Qualifying Facility Production Variation

	Conservation & Load Curtailments		
	Crisis Response Conservation	Price Demand Elasticity	Assumed MW of QF Outages
Jul '01	4.0%	2.0%	774
Aug '01	4.0%	2.0%	774
Sep '01	4.0%	2.0%	774
Oct '01	4.0%	2.0%	776
Nov '01	4.0%	2.0%	778
Dec '01	4.0%	2.0%	779
Jan '02	4.0%	3.0%	772
Jan '03	3.0%	2.0%	761
Jan '04	2.0%	2.0%	754
Jan '05	2.0%	2.0%	722
Jan '06	2.0%	2.0%	679
Jan '07	1.5%	2.0%	662
Jan '08	1.0%	1.0%	578
Jan '09	1.0%	1.0%	556
Jan '10	1.0%	1.0%	530

Components of CDWR Purchases to Meet Net Short Requirements

- Long-term contracts (executed and agreement in principle)
- Conversion of California Independent System Operator ("CAISO") Summer Reliability Agreements to DWR bilateral contracts
- Implementation of the "20/20" conservation plan (2001-2002) (See Table 2)
- CAISO, IOU and/or DWR voluntary economic load curtailment programs to reduce net short energy requirements (2001-2002) (See Table 2)
- Additional long-term energy purchases which could be entered into by DWR
- Quarterly balance of month, day-ahead, and intra-day purchases in the short-term or spot market

Table 2
Peak Demand Reduction Impacts-Summer 2001
Assumed as Part of Means to Meet Net Short Energy Requirements

Peak Demand Impact (MW)	Price Rolled-in ($/MWh)	Program	Comments
1,820*	550	IOU Interruptible Programs	IOU pays for capacity and curtailed energy.
1,000*	1,054	CA ISO Demand Relief Programs (DRP) and Demand Bidding (DB) Programs	DWR, through the ISO pays for capacity and curtailed energy.
1,090*	185	Governor's 20/20 program	Expected maximum available load reduction over peak periods.
1,250	No cost	2% Reduction due to increase in customer Rates (revised from 3%)	2% Elasticity estimate beginning July 1, 2001, increasing to 3% January 2002 for customer lag.
1,670	No cost	4% Customer conservation as reaction to energy crisis	Portion of observed year-to-date reduction in load relative to last year.

*The total of the three load reduction programs are assumed to provide approximately 2,000 MW of average summer peak reduction to account for program overlap and monthly variance in customer response.

Key Assumptions and Considerations

- First quarter and much of second quarter 2001 required virtually all spot purchases with additional QFs off line and State required to purchase shortfall
- Actual contracted power increases with each quarter with significant increase in Summer 2001
- Additional power plants come on line with each quarter, increasing supply
- Conservation programs and consumer response to energy shortages reduced load significantly between Spring and Summer
- Load management programs implemented Summer 2001 and 2002 to reduce "on-peak" energy purchases
- QFs return to market progressively through the year
- Price elasticity from rate increase begins Summer 2001
- Spot market for purchase prices have come down in June and July due to larger volumes of contracts, the temperate weather and FERC floating price caps
- Longer term prices based increasingly upon negotiated prices already in place act as a hedge against spot market volatility

Prices for Short-Term Energy Purchases

- Short-term energy purchases are quantities of energy remaining to be met after DWR's long-term contracts and conservation/load management are quantified
- Prices reflect DWR short-term (one quarter or less) contracts in effect as of July 2001 and spot purchases
- Spot purchases are modeled using a generation dispatch and market clearing price model for all existing and anticipated new electric generation in the Western United States
- For July 1, 2001, through September 2002, spot prices are capped by projected effect of the FERC floating rate cap adopted on June 19, 2001
- Total estimated DWR purchases, including payments for load management, are shown on Table 3

Summary of Forecasted Net Short

Table 3 details, for each quarter, the following:

- Estimated statewide DWR energy purchases to meet net short energy purchases and average price/MWh
- Purchases are in excess of exact requirements. Some off-system sales by DWR will occur
- Energy purchases under contract (quantity and average price based on contract terms)
- Energy purchases in short-term market and block forward market, not presently under contract (quantity and average price based on a range of hourly spot market prices and block forward purchases)
- 2001 first quarter prices are actual purchases
- Figure 2 provides statewide, all-in average price taking into account both contract, short-term, load management, and non-contract power purchases

Table 3
Summary of Forecasted Net Short Purchases
(Total Costs Only. Does Not Include Ratepayer Revenue)

		Total			Long-Term Contracted			Spot Purchases[1]			Load Management		
		Mwh (000s)	Total Cost ($000s)	Avg Price ($/Mwh)	Mwh (000s)	Total Cost ($000s)	Avg Price ($/Mwh)	Mwh (000s)	Total Cost ($000s)	Avg Price ($/Mwh)	Mwh (000s)	Total Cost ($1000s)	Avg Price ($/Mwh)
2001	Q1*	13,300	3,581,575	$ 269	N/A	N/A	N/A	13,300	3,581,575	$ 269	-	-	-
	Q2*	20,320	4,506,791	$ 222	4,749	627,582	$ 132	15,571	3,879,209	$ 249	-	-	-
	Q3	19,669	2,636,718	$ 134	6,700	823,769	$ 123	11,430	1,474,548	$ 129	1,539	338,400	$ 220
	Q4	16,572	1,910,457	$ 115	6,490	743,427	$ 115	10,082	1,167,031	$ 116	-	-	-
2002	Q1	15,331	1,472,607	$ 96	8,275	771,158	$ 93	7,056	701,450	$ 99	-	-	-
	Q2	15,748	1,413,672	$ 90	8,683	838,932	$ 97	6,552	471,940	$ 72	513	102,800	$ 200
	Q3	22,125	2,278,995	$ 103	13,348	1,260,702	$ 94	7,238	709,893	$ 98	1,539	308,400	$ 200
	Q4	18,223	1,633,597	$ 90	12,830	1,182,784	$ 92	5,394	450,813	$ 84	-	-	-
2003	Q1	18,910	1,430,614	$ 76	13,337	1,098,811	$ 82	5,573	331,803	$ 60	-	-	-
	Q2	19,626	1,435,231	$ 73	13,996	1,155,058	$ 83	5,629	280,173	$ 50	-	-	-
	Q3	24,557	1,920,936	$ 78	18,132	1,470,376	$ 81	6,425	450,560	$ 70	-	-	-
	Q4	22,302	1,668,847	$ 75	17,766	1,407,076	$ 79	4,536	261,771	$ 58	-	-	-
2004	Q1	23,254	1,584,330	$ 68	19,166	1,402,608	$ 73	4,088	181,722	$ 44	-	-	-
	Q2	22,915	1,542,713	$ 67	18,737	1,368,474	$ 73	4,178	174,238	$ 42	-	-	-
	Q3	27,603	1,801,316	$ 65	20,931	1,474,165	$ 70	6,672	327,151	$ 49	-	-	-
	Q4	25,683	1,689,187	$ 66	20,556	1,446,253	$ 70	5,127	242,934	$ 47	-	-	-
2005	Q1	22,110	1,379,762	$ 62	19,346	1,275,512	$ 66	2,764	104,250	$ 38	-	-	-
	Q2	23,612	1,419,867	$ 60	18,821	1,235,703	$ 66	4,791	184,164	$ 38	-	-	-
	Q3	28,374	1,694,872	$ 60	20,565	1,334,075	$ 65	7,809	360,797	$ 46	-	-	-
	Q4	24,414	1,475,963	$ 60	19,850	1,289,565	$ 65	4,565	186,398	$ 41	-	-	-
2006	Q1	21,065	1,238,162	$ 59	17,613	1,116,865	$ 63	3,452	121,298	$ 35	-	-	-
	Q2	21,615	1,260,076	$ 58	17,062	1,092,434	$ 64	4,553	167,642	$ 37	-	-	-
	Q3	27,273	1,569,684	$ 58	18,756	1,191,424	$ 64	8,517	378,260	$ 44	-	-	-
	Q4	23,405	1,387,779	$ 59	18,347	1,179,541	$ 64	5,058	208,238	$ 41	-	-	-
2007	Q1	21,824	1,280,768	$ 59	17,979	1,143,488	$ 64	3,846	137,281	$ 36	-	-	-
	Q2	21,929	1,296,038	$ 59	17,418	1,118,778	$ 64	4,510	177,260	$ 39	-	-	-
	Q3	27,094	1,590,506	$ 59	19,128	1,221,149	$ 64	7,966	369,356	$ 46	-	-	-
	Q4	23,747	1,428,301	$ 60	18,715	1,210,906	$ 65	5,032	217,395	$ 43	-	-	-
2008	Q1	22,885	1,389,257	$ 61	18,021	1,150,423	$ 64	4,864	238,834	$ 49	-	-	-
	Q2	23,521	1,268,295	$ 54	17,963	1,053,370	$ 59	5,559	214,926	$ 39	-	-	-
	Q3	28,696	1,710,804	$ 60	18,813	1,206,360	$ 64	9,883	504,444	$ 51	-	-	-
	Q4	25,531	1,521,048	$ 60	18,373	1,193,264	$ 65	7,159	327,785	$ 46	-	-	-
2009	Q1	23,645	1,381,005	$ 58	18,062	1,160,884	$ 64	5,584	220,120	$ 39	-	-	-
	Q2	24,142	1,406,595	$ 58	17,945	1,161,432	$ 65	6,197	245,163	$ 40	-	-	-
	Q3	30,331	1,895,439	$ 62	18,852	1,217,495	$ 65	11,478	677,943	$ 59	-	-	-
	Q4	26,348	1,580,296	$ 60	18,367	1,202,486	$ 65	7,980	377,809	$ 47	-	-	-
2010	Q1	25,166	1,461,086	$ 58	18,094	1,171,428	$ 65	7,072	289,657	$ 41	-	-	-
	Q2	26,075	1,521,808	$ 58	18,021	1,173,358	$ 65	8,054	348,450	$ 43	-	-	-
	Q3	33,247	2,181,698	$ 66	18,549	1,209,434	$ 65	14,699	972,263	$ 66	-	-	-
	Q4	27,881	1,666,254	$ 60	18,135	1,178,742	$ 65	9,745	487,511	$ 50	-	-	-

*Q1 and Q2 are actual costs, subject to final account reconciliation.

(1) Spot purchases include short-term (90 days and shorter) contracts in effect as of June 2001.

Figure 2
Actual and Projected California Gas Prices

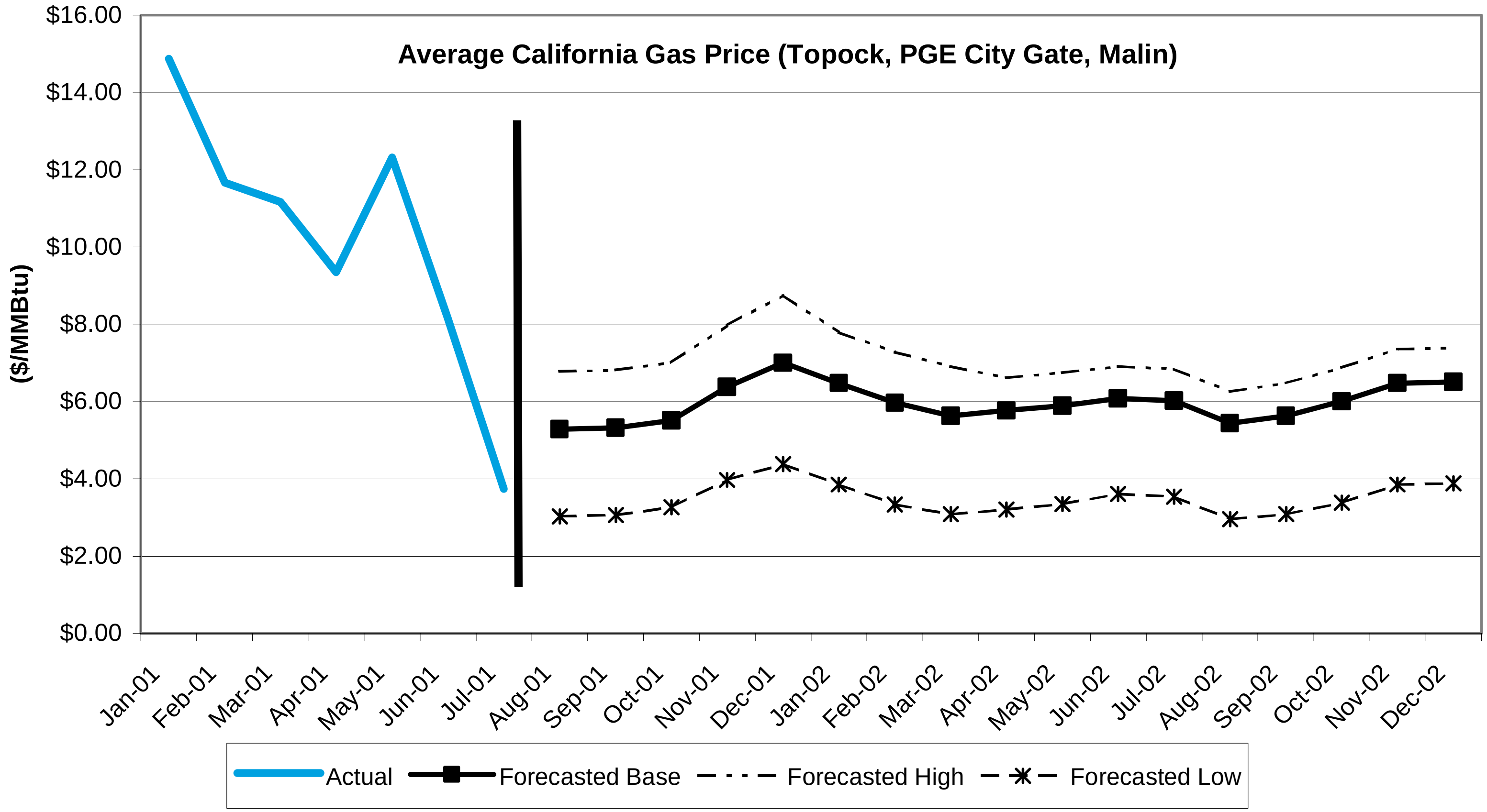
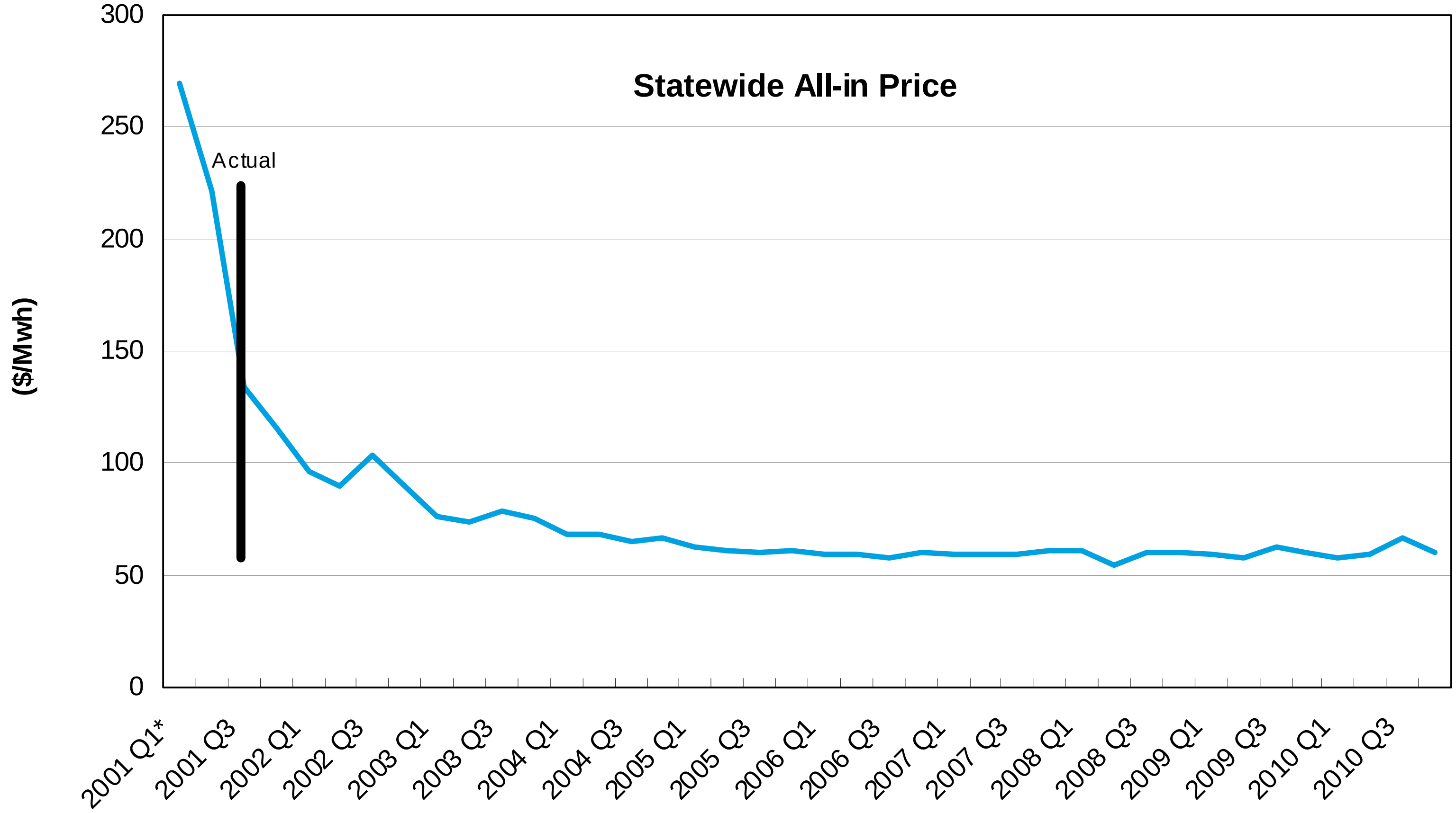


Figure 3
Actual and Projected Average Cost of Power
All-In Net Short Energy Power



Financing Plan Assumptions and Results

Energy Cost and Revenue Assumptions

- Rate increases for PG&E and SCE customers effective March 27, 2001 and begin to be received by DWR in September 2001; assumes PUC implements a corresponding rate increase for SDG&E customers
- Ratepayer revenue collections assume that DWR is entitled to the energy component in the January 5, 2001 rate structure of each IOU for DWR energy provided to each IOU's customers
- Ratepayer revenue collections assume that the PUC allocates to DWR, from rate increases, revenues sufficient (together with bond proceeds) to meet its revenue requirements
- Assumes DWR purchases ancillary service costs for IOU customers to the extent the IOUs cannot self-provide such services from utility retained generation

Table 4
DWR Expenditure Summary
($000s)

Quarter	Retail Sales (GWhs)	A&G	DSM	Contract Power	Residual Net Short	Ancillary Services	Total Commitments	(Lag) Lead Accrual to Cash	Total Operating Expenditures	Financing Cost	Total Expenditures	Customer Revenue Recovery
Q1, 2001	11,816	6,250	-	-	3,798,465	-	3,804,715	(1,462,461)	2,342,254	3,888	2,346,142	239,605
Q2, 2001	19,343	6,250	114,000	3,264,749	1,629,887	-	5,014,886	426,293	5,441,179	55,923	5,497,103	847,266
Q3, 2001	15,515	6,250	338,400	1,430,772	867,546	221,130	2,864,098	639,054	3,503,152	110,818	3,613,970	1,781,049
Q4, 2001	14,475	6,250	-	832,028	1,078,430	200,740	2,117,447	382,332	2,499,779	67,890	2,567,669	2,262,410
Q1, 2002	13,239	6,406	-	813,521	659,086	158,920	1,637,933	89,123	1,727,056	(34,324)	1,692,732	2,037,794
Q2, 2002	13,004	6,406	102,800	838,932	471,940	146,339	1,566,417	(119,566)	1,446,852	(40,469)	1,406,382	1,914,051
Q3, 2002	16,476	6,406	308,400	1,260,702	709,893	191,915	2,477,316	(113,673)	2,363,644	29,764	2,393,408	2,087,258
Q4, 2002	15,062	6,406	-	1,182,784	450,813	169,325	1,809,329	120,373	1,929,702	155,860	2,085,562	1,902,495
Total	118,930	50,625	863,600	9,623,488	9,666,060	1,088,368	21,292,142	(38,524)	21,253,618	349,349	21,602,967	13,071,928

Table 5
DWR Revenue Requirement
($000s)

Quarter	Retail Sales (GWhs)	Financing Cost	Total Expenditures	Customer Revenue Requirement	Quarterly Power Fund Flow	Net Bond Proceeds	Fund Balance
Q1, 2001	11,816	3,888	2,346,142	239,605	(2,106,537)	-	(2,106,537)
Q2, 2001	19,343	55,923	5,497,103	847,266	(4,649,837)	-	(6,756,374)
Q3, 2001	15,515	110,818	3,613,970	1,781,049	(1,832,920)	-	(8,589,294)
Q4, 2001	14,475	67,890	2,567,669	2,262,410	(305,260)	10,380,285	1,485,731
Q1, 2002	13,239	(34,324)	1,692,732	2,037,794	345,062	-	1,830,793
Q2, 2002	13,004	(40,469)	1,406,382	1,914,051	507,669	-	2,338,462
Q3, 2002	16,476	29,764	2,393,408	2,087,258	(306,149)	-	2,032,313
Q4, 2002	15,062	155,860	2,085,562	1,902,495	(183,067)	-	1,849,246
Total	118,930	349,349	21,602,967	13,071,928	(8,531,039)	10,380,285	

Bridge Loan and Bond

Bridge Loan	
• Bridge Loan Amount:	$4.3 Billion
• Bridge Loan Rate:	4.20%
Energy Bonds	
• Long-Term Tax-Exempt Energy Bond Issuance Date:	November 1, 2001*
• Long-Term Taxable Energy Bond Issuance Date:	November 1, 2001*
• Final Maturity of Long-Term Energy Bonds:	May 1, 2016
• Average Long-Term Tax-Exempt Interest Rate:	5.77%
• Average Long-Term Taxable Interest Rate:	7.77%
• Capitalized Interest Period:	12 Months
• Debt Service Reserve Fund:	$707 million
• Energy Bond Debt Service Coverage Requirement:	1.35 times
• Costs of Issuance:	1% of Bond Size

* Estimate subject to regulatory process and potential appeals.

Energy Program Bonding Parameters

DWR Revenue Requirement fits within existing approved rate structure for PG&E, SCE and SDG&E if a similar surcharge is approved in the pending SDG&E rate case

• Tax-Exempt Bond Issuance:	$8.5 Billion
• Taxable Bond Issuance:	$4.0 Billion
• Total Bond Issuance:	$12.5 Billion
• Minimum Fund Balance:	$1.85 Billion (1)
• Rolling Account Reserve:	$500 Million
• Projected 2001 Total Net Short Power Cost:	$13.32 Billion (2)
• Projected 2002 Total Net Short Power Cost:	$7.05 Billion (2)
• Projected 2003 Total Net Short Power Cost:	$5.44 Billion (2)

(1) During 2001-2002 period.

(2) Total costs only, not reduced by ratepayer revenues.